

Environmental Protection Agency

§ 98.233

distribution facilities must report stationary combustion emissions as specified in paragraph (i) of this section.

(1) You must report under subpart PP of this part (Suppliers of Carbon Dioxide), CO₂ emissions captured and transferred off site by following the requirements of subpart PP.

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 80574, Dec. 23, 2011]

§ 98.233 Calculating GHG emissions.

You must calculate and report the annual GHG emissions as prescribed in

this section. For actual conditions, reporters must use average atmospheric conditions or typical operating conditions as applicable to the respective monitoring methods in this section.

(a) *Natural gas pneumatic device venting.* Calculate CH₄ and CO₂ emissions from continuous high bleed, continuous low bleed, and intermittent bleed natural gas pneumatic devices using Equation W-1 of this section.

$$Mass_{t,i} = Count_t * EF_i * GHG_i * Conv_i * T_i \quad (\text{Eq. W-1})$$

Where:

Mass_{t,i} = Annual total mass GHG emissions in metric tons CO₂e per year from a natural gas pneumatic device vent of type “t”, for GHG_i.

Count_t = Total number of natural gas pneumatic devices of type “t” (continuous high bleed, continuous low bleed, intermittent bleed) as determined in paragraph (a)(1), (a)(2), and (a)(3) of this section.

EF_i = Population emission factors for natural gas pneumatic device venting listed in Tables W-1A, W-3, and W-4 of this subpart for onshore petroleum and natural gas production, onshore natural gas transmission compression, and underground natural gas storage facilities, respectively.

GHG_i = For onshore petroleum and natural gas production facilities, concentration of GHG_i, CH₄, or CO₂, in natural gas as defined in paragraph (u)(2)(i) of this section and for onshore natural gas transmission compression and underground natural gas storage, GHG_i equals 0.975 for CH₄ and 1.1×10^{-2} for CO₂.

Conv_i = Conversion from standard cubic feet to metric tons CO₂e; 0.000479 for CH₄, and 0.00005262 for CO₂.

T_i = Average estimated number of hours in the operating year the devices, of each type t, were operational. Default is 8760 hours.

(1) For onshore petroleum and natural gas production, provide the total number of continuous high bleed, continuous low bleed, or intermittent bleed natural gas pneumatic devices of each type as follows:

(i) In the first calendar year, for the total number of each type, you may

count the total of each type, or count any percentage number of each type plus an engineering estimate based on best available data of the number not counted.

(ii) In the second consecutive year, for the total number of each type, you may count the total of each type, or count any percentage number of each type plus an engineering estimate based on best available data of the number not counted.

(iii) In the third consecutive calendar year, complete the count of all pneumatic devices, including any changes to equipment counted in prior years.

(iv) For the calendar year immediately following the third consecutive calendar year, and for calendar years thereafter, facilities must update the total count of pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.

(2) For onshore natural gas transmission compression and underground natural gas storage, all natural gas pneumatic devices must be counted in the first year and updated every calendar year.

(3) For all industry segments, determine the type of pneumatic device using engineering estimates based on best available information.

(b) [Reserved]

(c) *Natural gas driven pneumatic pump venting.* Calculate CH₄ and CO₂ emissions from natural gas driven pneumatic pump venting using Equation W-2 of this section. Natural gas driven

pneumatic pumps covered in paragraph (e) of this section do not have to report

emissions under paragraph (c) of this section.

$$Mass_i = Count * EF * GHG_i * Conv_i * T \quad (\text{Eq. W-2})$$

Where:

Mass_i = Annual total mass GHG emissions in metric tons CO₂e per year from all natural gas pneumatic pump venting, for GHG_i.

Count = Total number of natural gas pneumatic pumps.

EF = Population emissions factors for natural gas pneumatic pump venting listed in Tables W-1A of this subpart for on-shore petroleum and natural gas production.

GHG_i = Concentration of GHG_i, CH₄, or CO₂, in produced natural gas as defined in paragraph (u)(2)(i) of this section.

Conv_i = Conversion from standard cubic feet to metric tons CO₂e; 0.000479 for CH₄, and 0.00005262 for CO₂.

T = Average estimated number of hours in the operating year the pumps were operational. Default is 8760 hours.

(d) *Acid gas removal (AGR) vents.* For AGR vent (including processes such as amine, membrane, molecular sieve or other adsorbents and adsorbents), calculate emissions for CO₂ only (not CH₄) vented directly to the atmosphere or through a flare, engine (*e.g.*, permeate from a membrane or de-adsorbed gas from a pressure swing adsorber used as fuel supplement), or sulfur recovery plant using any of the calculation methodologies described in paragraph (d) of this section, as applicable.

(1) *Calculation Methodology 1.* If you operate and maintain a CEMS that has both a CO₂ concentration monitor and volumetric flow rate monitor, you must calculate CO₂ emissions under this subpart by following the Tier 4 Calculation Methodology and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). Alternatively, you may follow the manufacturer's instructions or industry standard practice. If a CO₂ concentration monitor and volumetric flow rate monitor are not available, you may elect to install a CO₂ concentration monitor and a volumetric flow rate monitor that comply with all of the requirements specified for the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion). The calculation and reporting of CH₄ and N₂O emissions is not required as part of the Tier 4 requirements for AGRs.

(2) *Calculation Methodology 2.* If CEMS is not available but a vent meter is installed, use the CO₂ composition and annual volume of vent gas to calculate emissions using Equation W-3 of this section.

$$E_{a,CO_2} = V_S * Vol_{CO_2} \quad (\text{Eq. W-3})$$

where:

E_{a,CO₂} = Annual volumetric CO₂ emissions at actual conditions, in cubic feet per year.

V_S = Total annual volume of vent gas flowing out of the AGR unit in cubic feet per year at actual conditions as determined by flow meter using methods set forth in § 98.234(b). Alternatively, you may follow the manufacturer's instructions or industry standard practice for calibration of the vent meter.

Vol_{CO₂} = Volume fraction of CO₂ content in vent gas out of the AGR unit as determined in (d)(6) of this section.

(3) *Calculation Methodology 3.* If CEMS or a vent meter is not installed, you may use the inlet or outlet gas flow rate of the acid gas removal unit to calculate emissions for CO₂ using Equations W-4A or W-4B of this section. If inlet gas flow rate is known, use Equation W-4A. If outlet gas flow rate is known, use Equation W-4B.

$$E_{a,CO_2} = V_{in} * \left[\frac{Vol_I - Vol_O}{1 - Vol_O} \right] \quad (\text{Eq. W-4A})$$

$$E_{a,CO_2} = V_{out} * \left[\frac{Vol_I - Vol_O}{1 - Vol_I} \right] \quad (\text{Eq. W-4B})$$

Where:

E_{a, CO_2} = Annual volumetric CO₂ emissions at actual conditions, in cubic feet per year.

V_{in} = Total annual volume of natural gas flow into the AGR unit in cubic feet per year at actual condition as determined using methods specified in paragraph (d)(5) of this section.

V_{out} = Total annual volume of natural gas flow out of the AGR unit in cubic feet per year at actual condition as determined using methods specified in paragraph (d)(5) of this section.

Vol_I = Volume fraction of CO₂ content in natural gas into the AGR unit as determined in paragraph (d)(7) of this section.

Vol_O = Volume fraction of CO₂ content in natural gas out of the AGR unit as determined in paragraph (d)(8) of this section.

(4) *Calculation Methodology 4.* If CEMS or a vent meter is not installed, you may calculate emissions using any standard simulation software packages, such as AspenTech HYSYS® and API 4679 AMINECalc, that uses the Peng-Robinson equation of state, and speciates CO₂ emissions. A minimum of the following determined for typical operating conditions over the calendar year by engineering estimate and process knowledge based on best available data must be used to characterize emissions:

- (i) Natural gas feed temperature, pressure, and flow rate.
- (ii) Acid gas content of feed natural gas.
- (iii) Acid gas content of outlet natural gas.
- (iv) Unit operating hours, excluding downtime for maintenance or standby.
- (v) Exit temperature of natural gas.
- (vi) Solvent pressure, temperature, circulation rate, and weight.

(5) Record the gas flow rate of the inlet and outlet natural gas stream of an AGR unit using a meter according to methods set forth in §98.234(b). If you do not have a continuous flow

meter, either install a continuous flow meter or use an engineering calculation to determine the flow rate.

(6) If continuous gas analyzer is not available on the vent stack, either install a continuous gas analyzer or take quarterly gas samples from the vent gas stream to determine Vol_{CO_2} according to methods set forth in §98.234(b).

(7) If a continuous gas analyzer is installed on the inlet gas stream, then the continuous gas analyzer results must be used. If continuous gas analyzer is not available, either install a continuous gas analyzer or take quarterly gas samples from the inlet gas stream to determine Vol_I according to methods set forth in §98.234(b).

(8) Determine volume fraction of CO₂ content in natural gas out of the AGR unit using one of the methods specified in paragraph (d)(8) of this section.

(i) If a continuous gas analyzer is installed on the outlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, you may install a continuous gas analyzer.

(ii) If a continuous gas analyzer is not available or installed, quarterly gas samples may be taken from the outlet gas stream to determine Vol_O according to methods set forth in §98.234(b).

(iii) Use sales line quality specification for CO₂ in natural gas.

(9) Calculate CO₂ volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(10) Mass CO₂ emissions shall be calculated from volumetric CO₂ emissions using calculations in paragraph (v) of this section.

(11) Determine if emissions from the AGR unit are recovered and transferred

outside the facility. Adjust the emission estimated in paragraphs (d)(1) through (d)(10) of this section downward by the magnitude of emission recovered and transferred outside the facility.

(e) *Dehydrator vents.* For dehydrator vents, calculate annual CH₄, CO₂ and N₂O emissions using any of the calculation methodologies described in paragraph (e) of this section.

(1) *Calculation Methodology 1.* Calculate annual mass emissions from dehydrator vents with annual average daily throughput greater than or equal to 0.4 million standard cubic feet per day using a software program, such as AspenTech HYSYS® or GRI-GLYCalc, that uses the Peng-Robinson equation of state to calculate the equilibrium coefficient, speciates CH₄ and CO₂ emissions from dehydrators, and has provisions to include regenerator control devices, a separator flash tank, stripping gas and a gas injection pump or gas assist pump. A minimum of the following parameters determined by engineering estimate based on best available data must be used to characterize emissions from dehydrators:

- (i) Feed natural gas flow rate.
- (ii) Feed natural gas water content.
- (iii) Outlet natural gas water content.
- (iv) Absorbent circulation pump type (natural gas pneumatic/air pneumatic/electric).

(v) Absorbent circulation rate.

(vi) Absorbent type: including triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG).

(vii) Use of stripping gas.

(viii) Use of flash tank separator (and disposition of recovered gas).

(ix) Hours operated.

(x) Wet natural gas temperature and pressure.

(xi) Wet natural gas composition. Determine this parameter by selecting one of the methods described under paragraph (e)(1)(xi) of this section.

(A) Use the wet natural gas composition as defined in paragraph (u)(2)(i) or (u)(2)(ii) of this section.

(B) If wet natural gas composition cannot be determined using paragraph (u)(2)(i) or (u)(2)(ii) of this section, select a representative analysis.

(C) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as specified in § 98.234(b) to sample and analyze wet natural gas composition.

(D) If only composition data for dry natural gas is available, assume the wet natural gas is saturated.

(2) *Calculation Methodology 2.* Calculate annual CH₄ and CO₂ emissions from glycol dehydrators with annual average daily throughput less than 0.4 million standard cubic feet per day using Equation W-5 of this section:

$$E_{s,i} = EF_i * Count * 1000 \quad (\text{Eq. W-5})$$

where:

E_{s,i} = Annual total volumetric GHG emissions (either CO₂ or CH₄) at standard conditions in cubic feet.

EF_i = Population emission factors for glycol dehydrators in thousand standard cubic feet per dehydrator per year. Use 73.4 for CH₄ and 3.21 for CO₂ at 60 °F and 14.7 psia.

Count = Total number of glycol dehydrators with throughput less than 0.4 million standard cubic feet per day.

1000 = Conversion of EF_i in thousand standard cubic feet to standard cubic feet.

(3) Determine if dehydrator unit has vapor recovery. Adjust the emissions estimated in paragraphs (e)(1) or (e)(2)

of this section downward by the magnitude of emissions captured.

(4) Calculate annual emissions from dehydrator vents to flares or regenerator fire-box/fire tubes as follows:

(A) Use the dehydrator vent volume and gas composition as determined in paragraphs (e)(1) and (e)(2) of this section.

(B) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine dehydrator vent emissions from the flare or regenerator combustion gas vent.

(5) Dehydrators that use desiccant shall calculate emissions from the

Environmental Protection Agency

§ 98.233

amount of gas vented from the vessel when it is depressurized for the desiccant refilling process using Equation W-6 of this section. Desiccant

dehydrators covered in (e)(5) of this section do not have to report emissions under (i) of this section.

$$E_{s,n} = \frac{(H \cdot D^2 \cdot P \cdot P_2 \cdot \%G \cdot N)}{(4 \cdot P_1 \cdot 100)} \quad (\text{Eq. W-6})$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions in cubic feet.

H = Height of the dehydrator vessel (ft).

D = Inside diameter of the vessel (ft).

P_1 = Atmospheric pressure (psia).

P_2 = Pressure of the gas (psia).

P = pi (3.14).

%G = Percent of packed vessel volume that is gas.

N = Number of dehydrator openings in the calendar year.

100 = Conversion of %G to fraction.

(6) For glycol dehydrators, both CH_4 and CO_2 mass emissions shall be calculated from volumetric GHG_i emissions using calculations in paragraph (v) of this section. For dehydrators that use desiccant, both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(f) *Well venting for liquids unloadings.* Calculate CO_2 and CH_4 emissions from

well venting for liquids unloading using one of the calculation methodologies described in paragraphs (f)(1), (f)(2) or (f)(3) of this section.

(1) *Calculation Methodology 1.* For at least one well of each unique well tubing diameter group and pressure group combination in each sub-basin category (see §98.238 for the definitions of tubing diameter group, pressure group, and sub-basin category), where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing, a recording flow meter shall be installed on the vent line used to vent gas from the well (e.g., on the vent line off the wellhead separator or atmospheric storage tank) according to methods set forth in §98.234(b). Calculate emissions from well venting for liquids unloading using Equation W-7 of this section.

$$E_{a,n} = \sum_{p=1}^h T_p FR \quad (\text{Eq. W-7})$$

Where:

$E_{a,n}$ = Annual natural gas emissions for all wells of the same tubing diameter group and pressure group combination in a sub-basin at actual conditions in cubic feet.

h = Total number of wells of the same tubing diameter group and pressure group combination in a sub-basin.

p = Wells 1 through h of the same tubing diameter group and pressure group combination in a sub-basin.

T_p = Cumulative amount of time in hours of venting for each well, p, of the same tubing diameter group and pressure group combination in a sub-basin during the year.

FR = Average flow rate in cubic feet per hour for all measured wells venting for the duration of the liquids unloading, under actual conditions as determined in paragraph (f)(1)(i) of this section.

(i) Determine the well vent average flow rate as specified under paragraph (f)(1)(i) of this section for at least one well in a unique well tubing diameter group and pressure group combination in each sub-basin category.

(A) The average flow rate per hour of venting is calculated for each unique tubing diameter group and pressure group combination in each sub-basin category by dividing the recorded total

flow by the recorded time (in hours) for all measured liquid unloading events with venting to the atmosphere.

(B) This average flow rate per hour is applied to all wells in the same pressure group that have the same tubing diameter group, for the number of hours of venting these wells.

(C) A new average flow rate is calculated every other calendar year for each reporting sub-basin category starting the first calendar year of data

collection. For a new producing sub-basin category, an average flow rate is calculated beginning in the first year of production.

(ii) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(2) *Calculation Methodology 2.* Calculate the total emissions for well venting for liquids unloading using Equation W-8 of this section.

$$E_{s,n} = \sum_{p=1}^W \left[V_p \times \left((0.37 \times 10^{-3}) \times CD_p^2 \times WD_p \times SP_p \right) + \sum_{q=1}^{V_p} \left(SFR_p \times (HR_{p,q} - 1.0) \times Z_{p,q} \right) \right] \quad (\text{Eq. W-8})$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions, in cubic feet/year.

W = Total number of wells with well venting for liquids unloading for each sub-basin. $0.37 \times 10^{-3} = \{3.14 (\pi)/4\} / \{14.7 \times 144\}$ (psia converted to pounds per square feet).

CD_p = Casing internal diameter for each well, p, in inches.

WD_p = Well depth from either the top of the well or the lowest packer to the bottom of the well, for each well, p, in feet.

SP_p = For each well, p, shut-in pressure or surface pressure for wells with tubing production or casing pressure for each well with no packers in pounds per square inch absolute (psia); or casing-to-tubing pressure ratio of one well with no packer from the same sub-basin multiplied by the tubing pressure of each well, p, in the sub-basin, in pounds per square inch absolute (psia).

V_p = Number of unloading events per year per well, p.

SFR_p = Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation W-33 to calculate the average flow-line rate at standard conditions.

$HR_{p,q}$ = Hours that each well, p, was left open to the atmosphere during each unloading event, q.

1.0 = Hours for average well to blowdown casing volume at shut-in pressure.

$Z_{p,q}$ = If $HR_{p,q}$ is less than 1.0 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 1.0 then $Z_{p,q}$ is equal to 1.

(3) *Calculation Methodology 3.* Calculate emissions from well venting to the atmosphere for liquids unloading with plunger lift assist using Equation W-9 of this section.

$$E_{s,n} = \sum_{p=1}^W \left[V_p \times \left((0.37 \times 10^{-3}) \times TD_p^2 \times WD_p \times SP_p \right) + \sum_{q=1}^{V_p} \left(SFR_p \times (HR_{p,q} - 0.5) \times Z_{p,q} \right) \right] \quad (\text{Eq. W-9})$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions, in cubic feet/year.

W = Total number of wells with plunger lift assist and well venting for liquids unloading for each sub-basin.

$0.37 \times 10^{-3} = \{3.14 (\pi)/4\} / \{14.7 \times 144\}$ (psia converted to pounds per square feet).

TD_p = Tubing internal diameter for each well, p, in inches.

WD_p = Tubing depth to plunger bumper for each well, p, in feet.

SP_p = Flow-line pressure for each well, p, in pounds per square inch absolute (psia),

using engineering estimate based on best available data.

V_p = Number of unloading events per year for each well, p.

SFR_p = Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation W-33 to calculate the average flow-line rate at standard conditions.

$HR_{p,q}$ = Hours that each well, p, was left open to the atmosphere during each unloading event, q.

0.5 = Hours for average well to blowdown tubing volume at flow-line pressure.

Environmental Protection Agency

§ 98.233

$Z_{p,q}$ = If $HR_{p,q}$ is less than 0.5 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 0.5 then $Z_{p,q}$ is equal to 1.

(i)-(ii) [Reserved]

(4) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(g) *Gas well venting during completions and workovers from hydraulic fracturing.* Calculate CH_4 , CO_2 and N_2O annual emissions from gas well venting during completions involving hydraulic fracturing in wells and well workovers using Equation W-10A or Equation W-10B of this section. Equation W-10A applies to well venting when the backflow rate is measured or calculated, Equa-

tion W-10B applies when the backflow vent or flare volume is measured. Use Equation W-10A if the flow rate for backflow during well completions and workovers from hydraulic fracturing is known for the specified number of wells per paragraph (g)(1) in a sub-basin and well type (horizontal or vertical) combination. Use Equation W-10B if the flow volume for backflow during well completions and workovers from hydraulic fracturing is known for all wells in a sub-basin and well type (horizontal or vertical) combination. Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric total gas emissions using calculations in paragraphs (u) and (v) of this section.

$$E_{s,n} = \sum_{p=1}^W [T_p \times FRM_s \times PR_{s,p} - EnF_{s,p} - SG_{s,p}] \quad (\text{Eq. W-10A})$$

$$E_{s,n} = \sum_{p=1}^W [FV_{s,p} - EnF_{s,p}] \quad (\text{Eq. W-10B})$$

Where:

$E_{s,n}$ = Annual volumetric total gas emissions in cubic feet at standard conditions from gas well venting during completions or workovers following hydraulic fracturing for each sub-basin and well type (horizontal vs. vertical) combination.

W = Total number of wells completed or worked over using hydraulic fracturing in a sub-basin and well type (horizontal vs. vertical) combination.

T_p = Cumulative amount of time of backflow for the completion or workover, in hours, for each well, p , in a sub-basin and well type (horizontal vs. vertical) combination during the reporting year.

FRM_s = Ratio of flowback during well completions and workovers from hydraulic fracturing to 30-day production rate from Equation W-12.

$PR_{s,p}$ = First 30-day average production flow rate in standard cubic feet per hour of each well p , as required in paragraph (g)(1) of this section.

$EnF_{s,p}$ = Volume of CO_2 or N_2 injected gas in cubic feet at standard conditions that was injected into the reservoir during an energized fracture job for each well p . If the fracture process did not inject gas

into the reservoir, then $EnF_{s,p}$ is 0. If injected gas is CO_2 then $EnF_{s,p}$ is 0.

$SG_{s,p}$ = Volume of natural gas in cubic feet at standard conditions that was recovered into a flow-line for well p as per paragraph (g)(3) of this section. This parameter includes any natural gas that is injected into the well for clean-up. If no gas was recovered, $SG_{s,p}$ is 0.

$FV_{s,p}$ = Flow volume of each well (p) in standard cubic feet measured using a recording flow meter (digital or analog) on the vent line to measure flowback during the completion or workover according to methods set forth in § 98.234(b).

(1) The average flow rate for flowback during well completions and workovers from hydraulic fracturing shall be determined using measurement(s) for Calculation Methodology 1 or calculation(s) for Calculation Methodology 2 described in this paragraph (g)(1) of this section. If Equation W-10A is used, the number of measurements or calculations shall be determined per sub-basin and well type (horizontal or vertical) as follows: at least one measurement or calculation for less than or

equal to 25 completions or workovers; at least two measurements or calculations for 26 to 50 completions or workovers; at least three measurements or calculations for 51 to 100 completions or workovers; at least four measurements or calculations for 101 to 250 completions or workovers; and at least five measurements or calculations for greater than 250 completions or workovers.

(i) *Calculation Methodology 1.* When using Equation W-10A, for each measured well completion(s) in each gas producing sub-basin category and well type (horizontal or vertical) combination and for each measured well workover(s) in each gas producing sub-basin category and well type (horizontal or vertical) combination, a recording flow meter (digital or analog) shall be installed on the vent line, ahead of a flare or vent if used, to measure the backflow rate according to methods set forth in § 98.234(b).

(ii) *Calculation Methodology 2.* When using Equation W-10A, for each calculated horizontal well completion and each calculated vertical well completion in each gas producing sub-basin category and for each calculated well horizontal workover and for each calculated vertical well workover in each gas producing sub-basin category, record the well flowing pressure upstream (and downstream in subsonic flow) of a well choke according to methods set forth in § 98.234(b) to calculate the well backflow during well completions and workovers from hydraulic fracturing. Calculate emissions using Equation W-11A of this section for subsonic flow or Equation W-11B of this section for sonic flow. Use best engineering estimate based on best available data along with Equation W-11C of this section to determine whether the predominant flow is sonic or subsonic. If the value of R in Equation W-11C is greater than or equal to 2, then flow is sonic; otherwise, flow is subsonic:

$$FR_a = 1.27 * 10^5 * A * \sqrt{3430 * T_u * \left[\left(\frac{P_2}{P_1} \right)^{1.515} - \left(\frac{P_2}{P_1} \right)^{1.758} \right]} \quad (\text{Eq. W-11A})$$

Where:

FR_a = Average flow rate in cubic feet per hour, under actual subsonic flow conditions.

A = Cross sectional open area of the restriction orifice (m²).

P₁ = Upstream pressure (psia).

T_u = Upstream temperature (degrees Kelvin).

P₂ = Downstream pressure (psia).

3430 = Constant with units of m²/(sec² * K).

1.27*10⁵ = Conversion from m³/second to ft³/hour.

$$FR_a = 1.27 * 10^5 * A * \sqrt{187.08 * T_u} \quad (\text{Eq. W-11B})$$

Where:

FR_a = Average flow rate in cubic feet per hour, under actual sonic flow conditions.

A = Cross sectional open area of the restriction orifice (m²).

T_u = Upstream temperature (degrees Kelvin).

187.08 = Constant with units of m²/(sec² * K).

1.27*10⁵ = Conversion from m³/second to ft³/hour.

$$R = P_1 / P_2 \quad (\text{Eq. W-11C})$$

Where:

R = Pressure ratio

Environmental Protection Agency

§ 98.233

P1 = Pressure upstream of the restriction orifice in pounds per square inch absolute.

P2 = Pressure downstream of the restriction orifice in pounds per square inch absolute.

(iii) For Equation W-10A, the ratio of backflow rate during well completions and workovers from hydraulic fracturing to 30-day production rate is calculated using Equation W-12 of this section.

$$FRM_s = \frac{\sum_{p=1}^N FR_{s,p}}{\sum_{p=1}^N PR_{s,p}} \quad (\text{Eq. W-12})$$

Where:

FRM_s = Ratio of flowback rate during well completions and workovers from hydraulic fracturing to 30-day production rate.

FR_{s,p} = Measured flowback rate from Calculation Methodology 1 described in paragraph (g)(1)(i) of this section or calculated flow rate from Calculation Methodology 2 described in paragraph (g)(1)(ii) of this section in standard cubic feet per hour for well(s) p for each sub-basin and well type (horizontal or vertical) combination. Measured and calculated FR_s values shall be converted from actual conditions (FR_a) to standard conditions (FR_{s,p}) for each well p using Equation W-33 in paragraph (t) of this section. You may not use flow volume as used in Equation W-10B converted to a flow rate for this parameter.

PR_{s,p} = First 30-day production rate in standard cubic feet per hour for each well p that was measured in the sub-basin and well type combination.

N = Number of measured or calculated well completions or workovers using hydraulic fracturing in a sub-basin and well type combination.

(iv) For Equation W-10A, the ratio of backflow rate during well completions and workovers from hydraulic fracturing to 30-day production rate for horizontal and vertical wells are applied to all horizontal and vertical well completions in the gas producing sub-basin and well type combination and to all horizontal and vertical well workovers, respectively, in the gas producing sub-basin and well type combination for the total number of hours of backflow for each of these wells.

(v) For Equation W-10A, new flow rates for horizontal and vertical gas well completions and horizontal and

vertical gas well workovers in each sub-basin category shall be calculated once every two years starting in the first calendar year of data collection.

(2) The volume of CO₂ or N₂ injected into the well reservoir during energized hydraulic fractures will be measured using an appropriate meter as described in 98.234(b) or using receipts of gas purchases that are used for the energized fracture job.

(i) Calculate gas volume at standard conditions using calculations in paragraph (t) of this section.

(ii) [Reserved]

(3) Determine if the backflow gas from the well completion or workover from hydraulic fracturing is recovered with purpose designed equipment that separates natural gas from the backflow, and sends this natural gas to a flow-line (e.g., reduced emissions completion or workovers).

(i) Use the factor SG_{s,p} in Equation W-10A of this section, to adjust the emissions estimated in paragraphs (g)(1) through (g)(4) of this section by the magnitude of emissions captured using purpose designed equipment that separates saleable gas from the flowback as determined by engineering estimate based on best available data.

(ii) [Reserved]

(iii) Calculate gas volume at standard conditions using calculations in paragraph (t) of this section.

(4) Both CH₄ and CO₂ volumetric and mass emissions shall be calculated from volumetric total emissions using calculations in paragraphs (u) and (v) of this section.

(5) Calculate annual emissions from gas well venting during well completions and workovers from hydraulic fracturing to flares as follows:

(i) Use the total gas well venting volume during well completions and workovers as determined in paragraph (g) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine gas well venting during well completions and workovers using hydraulic fracturing emissions

from the flare. This adjustment to emissions from completions using flaring versus completions without flaring accounts for the conversion of CH₄ to CO₂ in the flare.

(h) *Gas well venting during completions and workovers without hydraulic fracturing.* Calculate CH₄, CO₂ and N₂O emissions from each gas well venting during well completions and workovers not involving hydraulic fracturing using Equation W-13 of this section:

$$E_{s,n} = N_{wo} * EF_{wo} + \sum_{p=1}^f V_p * T_p \quad (\text{Eq. W-13})$$

Where:

E_{s,n} = Annual natural gas emissions in standard cubic feet from gas well venting during well completions and workovers without hydraulic fracturing.

N_{wo} = Number of workovers per sub-basin category that flare gas or vent gas to the atmosphere and do not involve hydraulic fracturing in the reporting year.

EF_{wo} = Emission Factor for non-hydraulic fracture well workover venting in standard cubic feet per workover. EF_{wo} = 3114 standard cubic feet natural gas per well workover without hydraulic fracturing.

p = Well completions 1 through f in a sub-basin.

f = Total number of well completions without hydraulic fracturing in a sub-basin category.

V_p = Average daily gas production rate in standard cubic feet per hour for each well completion without hydraulic fracturing, p. This is the total annual gas production volume divided by total number of hours the wells produced to the flow-line. For completed wells that have not established a production rate, you may use the average flow rate from the first 30 days of production. In the event that the well is completed less than 30 days from the end of the calendar year, the first 30 days of the production straddling the current and following calendar years shall be used.

T_p = Time each well completion without hydraulic fracturing, p, was venting in hours during the year.

(1) Volumetric emissions for both CH₄ and CO₂ shall be calculated from volumetric natural gas emissions using calculations in paragraph (u) of this sec-

tion. Mass emissions for both CH₄ and CO₂ shall be calculated from volumetric natural gas emissions using calculations in paragraphs (v) of this section.

(2) Calculate annual emissions from gas well venting during well completions and workovers not involving hydraulic fracturing to flares as follows:

(i) Use the gas well venting volume during well completions and workovers as determined in paragraph (h) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine gas well venting during well completions and workovers emissions without hydraulic fracturing from the flare.

(i) *Blowdown vent stacks.* Calculate CO₂ and CH₄ blowdown vent stack emissions from depressurizing equipment(s) to reduce system pressure for planned or emergency shutdowns resulting from human intervention or to take equipment out of service for maintenance (excluding depressurizing to a flare, over-pressure relief, operating pressure control venting and blowdown of non-GHG gases; desiccant dehydrator blowdown venting before reloading is covered in paragraph (e)(5) of this section) as follows:

(1) Calculate the unique physical volume (including pipelines, compressor case or cylinders, manifolds, suction bottles, discharge bottles, and vessels) between isolation valves determined by

engineering estimates based on best available data.

(2) If the unique physical volume between isolation valves is greater than or equal to 50 cubic feet, retain logs of the number of blowdowns for each unique physical volume (including but not limited to compressors, vessels, pipelines, headers, fractionators, and

tanks). Unique physical volumes smaller than 50 cubic feet are exempt from reporting under paragraph (i) of this section.

(3) Calculate the total annual venting emissions for unique volumes using either Equation W-14A or W-14B of this section.

$$E_{s,n} = N * \left(V \left(\frac{(459.67 + T_s) P_a}{(459.67 + T_a) P_s} \right) - V * C \right) \quad (\text{Eq. W-14A})$$

Where:

$E_{s,n}$ = Annual natural gas venting emissions at standard conditions from blowdowns in cubic feet.

N = Number of occurrences of blowdowns for each unique physical volume in calendar year.

V = Unique physical volume (including pipelines, compressors and vessels) between isolation valves in cubic feet.

C = Purge factor that is 1 if the unique physical volume is not purged or zero if the

unique physical volume is purged using non-GHG gases.

T_s = Temperature at standard conditions (60 °F).

T_a = Temperature at actual conditions in the unique physical volume (°F).

P_s = Absolute pressure at standard conditions (14.7 psia).

P_a = Absolute pressure at actual conditions in the unique physical volume (psia).

$$E_{s,n} = \sum_{p=1}^N \left[V \left(\frac{(459.67 + T_s) (P_{a,b,p} - P_{a,e,p})}{(459.67 + T_{a,p}) P_s} \right) \right] \quad (\text{Eq. W-14B})$$

Where:

$E_{s,n}$ = Annual natural gas venting emissions at standard conditions from blowdowns in cubic feet.

p = Individual occurrence of blowdown for the same unique physical volume.

N = Number of occurrences of blowdowns for each unique physical volume in the calendar year.

V = Total physical volume (including pipelines, compressors and vessels) between isolation valves in cubic feet for each blowdown "p".

T_s = Temperature at standard conditions (60 °F).

$T_{a,p}$ = Temperature at actual conditions in the unique physical volume (°F) for each blowdown "p".

P_s = Absolute pressure at standard conditions (14.7 psia).

$P_{a,b,p}$ = Absolute pressure at actual conditions in the unique physical volume (psia) at the beginning of the blowdown "p".

$P_{a,e,p}$ = Absolute pressure at actual conditions in the unique physical volume (psia) at the end of the blowdown "p"; 0 if blowdown volume is purged using non-GHG gases.

(4) Calculate both CH₄ and CO₂ volumetric and mass emissions using calculations in paragraph (u) and (v) of this section.

(j) *Onshore production storage tanks.* Calculate CH₄, CO₂ and N₂O (when flared) emissions from atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids from onshore petroleum and natural gas production facilities (including stationary liquid storage not owned or operated by the reporter), calculate annual CH₄ and CO₂ emissions using any of the calculation methodologies described in this paragraph (j).

(1) *Calculation Methodology 1.* For separators with annual average daily throughput of oil greater than or equal to 10 barrels per day. Calculate annual CH₄ and CO₂ emissions from onshore production storage tanks using operating conditions in the last wellhead gas-liquid separator before liquid transfer to storage tanks. Calculate flashing emissions with a software program, such as AspenTech HYSYS® or API 4697 E&P Tank, that uses the Peng-Robinson equation of state, models flashing emissions, and speciates CH₄ and CO₂ emissions that will result when the oil from the separator enters an atmospheric pressure storage tank. A minimum of the following parameters determined for typical operating conditions over the year by engineering estimate and process knowledge based on best available data must be used to characterize emissions from liquid transferred to tanks.

- (i) Separator temperature.
- (ii) Separator pressure.
- (iii) Sales oil or stabilized oil API gravity.
- (iv) Sales oil or stabilized oil production rate.
- (v) Ambient air temperature.
- (vi) Ambient air pressure.
- (vii) Separator oil composition and Reid vapor pressure. If this data is not available, determine these parameters by selecting one of the methods described under paragraph (j)(1) (vii) of this section.

(A) If separator oil composition and Reid vapor pressure default data are provided with the software program, select the default values that most closely match your separator pressure first, and API gravity secondarily.

(B) If separator oil composition and Reid vapor pressure data are available through your previous analysis, select the latest available analysis that is representative of produced crude oil or condensate from the sub-basin category.

(C) Analyze a representative sample of separator oil in each sub-basin category for oil composition and Reid vapor pressure using an appropriate standard method published by a consensus-based standards organization.

(2) *Calculation Methodology 2.* Calculate annual CH₄ and CO₂ emissions

from onshore production storage tanks for wellhead gas-liquid separators with annual average daily throughput of oil greater than or equal to 10 barrels per day by assuming that all of the CH₄ and CO₂ in solution at separator temperature and pressure is emitted from oil sent to storage tanks. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as described in § 98.234(b) to sample and analyze separator oil composition at separator pressure and temperature.

(3) *Calculation Methodology 3.* For wells with annual average daily oil production greater than or equal to 10 barrels per day that flow directly to atmospheric storage tanks without passing through a wellhead separator, calculate annual CH₄ and CO₂ emissions by either of the methods in paragraph (j)(3) of this section:

(i) If well production oil and gas compositions are available through your previous analysis, select the latest available analysis that is representative of produced oil and gas from the sub-basin category and assume all of the CH₄ and CO₂ in both oil and gas are emitted from the tank.

(ii) If well production oil and gas compositions are not available, use default oil and gas compositions in software programs, such as API 4697 E&P Tank, that most closely match your well production gas/oil ratio and API gravity and assume all of the CH₄ and CO₂ in both oil and gas are emitted from the tank.

(4) *Calculation Methodology 4.* For wells with annual average daily oil production greater than or equal to 10 barrels per day that flow to a separator not at the well pad, calculate annual CH₄ and CO₂ emissions by either of the methods in paragraph (j)(4) of this section:

(i) If well production oil and gas compositions are available through your previous analysis, select the latest available analysis that is representative of oil at separator pressure determined by best available data and assume all of the CH₄ and CO₂ in the oil is emitted from the tank.

(ii) If well production oil composition is not available, use default oil composition in software programs, such as API 4697 E&P Tank, that most closely match your well production API gravity and pressure in the off-well pad separator determined by best available data. Assume all of the CH₄ and CO₂ in the oil phase is emitted from the tank.

(5) *Calculation Methodology 5.* For well pad gas-liquid separators and for wells flowing off a well pad without passing through a gas-liquid separator with annual average daily throughput of oil less than 10 barrels per day use Equation W-15 of this section:

$$E_{s,i} = EF_i * Count * 1000 \quad (\text{Eq. W-15})$$

where:

E_{s,i} = Annual total volumetric GHG emissions (either CO₂ or CH₄) at standard conditions in cubic feet.

EF_i = Population emission factor for separators or wells in thousand standard cubic feet per separator or well per year, for crude oil use 4.2 for CH₄ and 2.8 for CO₂ at 60 °F and 14.7 psia, and for gas condensate use 17.6 for CH₄ and 2.8 for CO₂ at 60 °F and 14.7 psia.

Count = Total number of separators or wells with annual average daily throughput less than 10 barrels per day. Count only separators or wells that feed oil directly to the storage tank.

1,000 = Conversion from thousand standard cubic feet to standard cubic feet.

(6) Determine if the storage tank receiving your separator oil has a vapor recovery system.

(i) Adjust the emissions estimated in paragraphs (j)(1) through (j)(5) of this

section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

(ii) [Reserved]

(7) Determine if the storage tank receiving your separator oil is sent to flare(s).

(i) Use your separator flash gas volume and gas composition as determined in this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine your contribution to storage tank emissions from the flare.

(8) Calculate emissions from occurrences of well pad gas-liquid separator liquid dump valves not closing during the calendar year by using Equation W-16 of this section.

$$E_{s,i} = \left(CF_n * \frac{E_n}{8760} * T_n \right) + \left(\frac{E_n}{8760} * (8760 - T_n) \right) \quad (\text{Eq. W-16})$$

where:

E_{s,i} = Annual total volumetric GHG emissions at standard conditions from each storage tank in cubic feet.

E_n = Storage tank emissions as determined in Calculation Methodologies 1, 2, or 4 in paragraphs (j)(1), (j)(2) and (j)(4) of this section (with wellhead separators) in standard cubic feet per year.

T_n = Total time the dump valve is not closing properly in the calendar year in hours. T_n is estimated by maintenance or operations records (records) such that when a record shows the valve to be open improperly, it is assumed the valve was

open for the entire time period preceding the record starting at either the beginning of the calendar year or the previous record showing it closed properly within the calendar year. If a subsequent record shows it is closing properly, then assume from that time forward the valve closed properly until either the next record of it not closing properly or, if there is no subsequent record, the end of the calendar year.

CF_n = Correction factor for tank emissions for time period T_n is 3.87 for crude oil production. Correction factor for tank emissions for time period T_n is 5.37 for gas condensate production. Correction

§ 98.233

40 CFR Ch. I (7–1–14 Edition)

factor for tank emissions for time period T_n is 1.0 for periods when the dump valve is closed.

8,760 = Conversion to hourly emissions.

(9) Calculate both CH_4 and CO_2 mass emissions from volumetric natural gas emissions using calculations in paragraph (v) of this section.

(k) *Transmission storage tanks.* For vent stacks connected to one or more transmission condensate storage tanks, either water or hydrocarbon, without vapor recovery, in onshore natural gas transmission compression, calculate CH_4 , CO_2 and N_2O annual emissions from compressor scrubber dump valve leakage as follows:

(1) Monitor the tank vapor vent stack annually for emissions using an optical gas imaging instrument according to methods set forth in § 98.234(a)(1) or by directly measuring the tank vent using a flow meter or high volume sampler according to methods in § 98.234(b) through (d) for a duration of 5 minutes, or a calibrated bag according to methods in § 98.234(b). Or you may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods set forth in § 98.234(a)(5).

(2) If the tank vapors from the vent stack are continuous for 5 minutes, or the acoustic leak detection device detects a leak, then use one of the following two methods in paragraph (k)(2) of this section to quantify annual emissions:

(i) Use a meter, such as a turbine meter, calibrated bag, or high flow sampler to estimate tank vapor volumes from the vent stack according to methods set forth in § 98.234(b) through (d). If you do not have a continuous flow measurement device, you may install a flow measuring device on the tank vapor vent stack. If the vent is directly measured for five minutes under paragraph § 98.233(k)(1) of this section to detect continuous leakage, this serves as the measurement.

(ii) Use an acoustic leak detection device on each scrubber dump valve connected to the tank according to the method set forth in § 98.234(a)(5).

(iii) Use the appropriate gas composition in paragraph (u)(2)(iii) of this section.

(iv) Calculate GHG volumetric and mass emissions at standard conditions using calculations in paragraphs (t), (u), and (v) of this section, as applicable to the monitoring equipment used.

(3) If the leaking dump valve(s) is fixed following leak detection, the annual emissions shall be calculated from the beginning of the calendar year to the time the valve(s) is repaired.

(4) Calculate annual emissions from storage tanks to flares as follows:

(i) Use the storage tank emissions volume and gas composition as determined in paragraphs (k)(1) through (k)(3) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine storage tank emissions sent to a flare.

(1) *Well testing venting and flaring.* Calculate CH_4 , CO_2 and N_2O (when flared) well testing venting and flaring emissions as follows:

(1) Determine the gas to oil ratio (GOR) of the hydrocarbon production from oil well(s) tested. Determine the production rate from gas well(s) tested.

(2) If GOR cannot be determined from your available data, then you must measure quantities reported in this section according to one of the two procedures in paragraph (1)(2) of this section to determine GOR:

(i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(ii) Or you may use an industry standard practice as described in § 98.234(b).

(3) Estimate venting emissions using Equation W-17A or Equation W-17B of this section.

$$E_{a,n} = GOR * FR * D \quad (\text{Eq. W-17A})$$

$$E_{a,n} = PR * D \quad (\text{Eq. W-17B})$$

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions from well(s) testing in cubic feet under actual conditions.

GOR = Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

FR = Flow rate in barrels of oil per day for the oil well(s) being tested.

PR = Average annual production rate in actual cubic feet per day for the gas well(s) being tested.

D = Number of days during the year, the well(s) is tested.

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(5) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(6) Calculate emissions from well testing to flares as follows:

(i) Use the well testing emissions volume and gas composition as determined in paragraphs (1)(1) through (3) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this

section to determine well testing emissions from the flare.

(m) *Associated gas venting and flaring.* Calculate CH_4 , CO_2 and N_2O (when flared) associated gas venting and flaring emissions not in conjunction with well testing (refer to paragraph (1): Well testing venting and flaring of this section) as follows:

(1) Determine the GOR of the hydrocarbon production from each well whose associated natural gas is vented or flared. If GOR from each well is not available, the GOR from a cluster of wells in the same sub-basin category shall be used.

(2) If GOR cannot be determined from your available data, then use one of the two procedures in paragraph (m)(2) of this section to determine GOR:

(i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(ii) Or you may use an industry standard practice as described in § 98.234(b).

(3) Estimate venting emissions using Equation W-18 of this section.

$$E_{a,n} = \sum_{q=1}^y \sum_{p=1}^x GOR_{p,q} * V_{p,q} \quad (\text{Eq. W-18})$$

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions, at the facility level, from associated gas venting under actual conditions, in cubic feet.

$GOR_{p,q}$ = Gas to oil ratio, for well p in sub-basin q, in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

$V_{p,q}$ = Volume of oil produced, for well p in sub-basin q, in barrels in the calendar year during which associated gas was vented or flared.

x = Total number of wells in sub-basin that vent or flare associated gas.

y = Total number of sub-basins in a basin that contain wells that vent or flare associated gas.

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(5) Calculate both CH₄ and CO₂ volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(6) Calculate emissions from associated natural gas to flares as follows:

(i) Use the associated natural gas volume and gas composition as determined in paragraph (m)(1) through (4) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine associated gas emissions from the flare.

(n) *Flare stack emissions.* Calculate CO₂, CH₄, and N₂O emissions from a flare stack as follows:

(1) If you have a continuous flow measurement device on the flare, you must use the measured flow volumes to calculate the flare gas emissions. If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If you do not have a continuous flow measurement device on the flare, you can install a flow measuring device on the flare or use engineering calculations based on process knowledge, company records, and best available data.

(2) If you have a continuous gas composition analyzer on gas to the flare, you must use these compositions in calculating emissions. If you do not have a continuous gas composition analyzer on gas to the flare, you must use

the appropriate gas compositions for each stream of hydrocarbons going to the flare as follows:

(i) For onshore natural gas production, determine natural gas composition using (u)(2)(i) of this section.

(ii) For onshore natural gas processing, when the stream going to flare is natural gas, use the GHG mole percent in feed natural gas for all streams upstream of the de-methanizer or dew point control, and GHG mole percent in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole percent in feed natural gas liquid for all streams.

(iii) For any applicable industry segment, when the stream going to the flare is a hydrocarbon product stream, such as methane, ethane, propane, butane, pentane-plus and mixed light hydrocarbons, then you may use a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data.

(3) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 98 percent.

(4) Calculate GHG volumetric emissions at actual conditions using Equations W-19, W-20, and W-21 of this section.

$$E_{a,CH_4}(un-combusted) = V_a * (1 - \eta) * X_{CH_4} \quad (\text{Eq. W-19})$$

$$E_{a,CO_2}(un-combusted) = V_a * X_{CO_2} \quad (\text{Eq. W-20})$$

$$E_{a,CO_2}(combusted) = \sum_{j=1}^5 (\eta * V_a * Y_j * R_j) \quad (\text{Eq. W-21})$$

where:

$E_{a,CH_4}(un-combusted)$ = Contribution of annual un-combusted CH₄ emissions from

flare stack in cubic feet, under actual conditions.

Environmental Protection Agency

§ 98.233

$E_{a,CO_2}(\text{un-combusted})$ = Contribution of annual un-combusted CO_2 emissions from flare stack in cubic feet, under actual conditions.

$E_{a,CO_2}(\text{combusted})$ = Contribution of annual combusted CO_2 emissions from flare stack in cubic feet, under actual conditions.

V_a = Volume of gas sent to flare in cubic feet, during the year.

η = Fraction of gas combusted by a burning flare (default is 0.98). For gas sent to an unlit flare, η is zero.

X_{CH_4} = Mole fraction of CH_4 in gas to the flare.

X_{CO_2} = Mole fraction of CO_2 in gas to the flare.

Y_j = Mole fraction of gas hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes-plus).

R_j = Number of carbon atoms in the gas hydrocarbon constituent j : 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes-plus).

(5) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(6) Calculate both CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (v) of this section.

(7) [Reserved]

(8) Calculate N_2O emissions from flare stacks using Equation W-40 in paragraph (z) of this section.

(9) If you operate and maintain a CEMS that has both a CO_2 concentration monitor and volumetric flow rate monitor, you must calculate only CO_2 emissions for the flare. You must follow the Tier 4 Calculation Methodology and all associated calculation, quality assurance, reporting, and record-keeping requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). If a CEMS is used to calculate flare stack emissions, the requirements specified in paragraphs (n)(1) through (n)(7) are not required. If a CO_2 concentration monitor and volumetric flow rate monitor are not available, you may elect to install a CO_2 concentration monitor and a volumetric flow rate monitor that comply with all of the requirements specified for the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion).

(10) The flare emissions determined under paragraph (n) of this section must be corrected for flare emissions

calculated and reported under other paragraphs of this section to avoid double counting of these emissions.

(11) If source types in § 98.233 use Equations W-19 through W-21 of this section, use estimate of emissions under actual conditions for the parameter, V_a , in these equations.

(o) *Centrifugal compressor venting.* Calculate CH_4 , CO_2 and N_2O (when flared) emissions from both wet seal and dry seal centrifugal compressor vents as follows:

(1) For each centrifugal compressor covered by § 98.232 (d)(2), (e)(2), (f)(2), (g)(2), and (h)(2) you must conduct an annual measurement in the operating mode in which it is found. Measure emissions from all vents (including emissions manifolded to common vents) including wet seal oil degassing vents, unit isolation valve vents, and blowdown valve vents. Record emissions from the following vent types in the specified compressor modes during the annual measurement.

(i) Operating mode, blowdown valve leakage through the blowdown vent, wet seal and dry seal compressors.

(ii) Operating mode, wet seal oil degassing vents.

(iii) Not operating, depressurized mode, unit isolation valve leakage through open blowdown vent, without blind flanges, wet seal and dry seal compressors.

(A) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode.

(2) For wet seal oil degassing vents, determine vapor volumes sent to an atmospheric vent or flare, using a temporary meter such as a vane anemometer or permanent flow meter according to § 98.234(b) of this section. If you do not have a permanent flow meter, you may install a permanent flow meter on the wet seal oil degassing tank vent.

§ 98.233

40 CFR Ch. I (7–1–14 Edition)

(3) For blowdown valve leakage and unit isolation valve leakage to open ended vents, you can use one of the following methods: Calibrated bagging or high volume sampler according to methods set forth in § 98.234(c) and § 98.234(d), respectively. For through valve leakage, such as isolation valves, you may use an acoustic leak detection

device according to methods set forth in § 98.234(a). If you do not have a flow meter, you may install a port for insertion of a temporary meter, or a permanent flow meter, on the vents.

(4) Estimate annual emissions using the flow measurement and Equation W-22 of this section.

$$E_{s,i,m} = MT_m * T_m * M_{i,m} * (1 - B_m) \quad (\text{Eq. W-22})$$

where:

$E_{s,i,m}$ = Annual GHG_i (either CH₄ or CO₂) volumetric emissions at standard conditions, in cubic feet.

MT_m = Measured gas emissions in standard cubic feet per hour.

T_m = Total time the compressor is in the mode for which $E_{s,i}$ is being calculated, in the calendar year in hours.

$M_{i,m}$ = Mole fraction of GHG_i in the vent gas; use the appropriate gas compositions in paragraph (u)(2) of this section.

B_m = Fraction of operating time that the vent gas is sent to vapor recovery or fuel gas as determined by keeping logs of the number of operating hours for the vapor recovery system and the time that vent gas is directed to the fuel gas system or sales.

(5) Calculate annual emissions from each centrifugal compressor using Equation W-23 of this section.

$$E_{s,i,m} = EF_m * T_m * GHG_i \quad (\text{Eq. W-23})$$

where:

$E_{s,i,m}$ = Annual total volumetric GHG emissions at standard conditions from each centrifugal compressor for mode-source combination m, in cubic feet.

EF_m = Reporter emission factor for each mode m, in cubic feet per hour, from Equation W-24 of this section as calculated in paragraph 6.

T_m = Total time in hours per year the compressor was in each mode, as listed in paragraph (o)(1)(i) through (o)(1)(iii).

GHG_i = For onshore natural gas processing facilities, concentration of GHG_i, CH₄ or CO₂, in produced natural gas or feed nat-

ural gas; for other facilities listed in § 98.230(a)(4) through (a)(8), GHG_i equals 1.

(6) You shall use the flow measurements of operating mode wet seal oil degassing vent, operating mode blowdown valve vent and not operating depressurized mode isolation valve vent for all the reporter's compressor modes not measured in the calendar year to develop the following emission factors using Equation W-24 of this section for each emission source and mode as listed in paragraph (o)(1)(i) through (o)(1)(iii).

$$EF_m = \frac{\sum_{p=1}^{Count_m} MT_{m,p}}{Count_m} \quad (\text{Eq. W-24})$$

where:

EF_m = Reporter emission factors for compressor in the three modes m (as listed in

paragraph (o)(1)(i) through (o)(1)(iii)) in cubic feet per hour.

Environmental Protection Agency

§ 98.233

MT_{m,p} = Flow measurements from all centrifugal compressor sources in each mode-source combination, m, for each measured compressor, p, in standard cubic feet per hour.

Count_m = Total number of compressors measured.

m = Compressor mode-source combination as listed in paragraphs (o)(1)(i) through (o)(1)(iii).

(i) The emission factors must be calculated annually. You must use all

measurements from the current calendar year and the preceding two calendar years, totaling three consecutive calendar years of measurements in paragraph (o)(6) of this section.

(ii) [Reserved]

(7) Onshore petroleum and natural gas production shall calculate emissions from centrifugal compressor wet seal oil degassing vents as follows:

$$E_{s,i} = \text{Count} * EF_i \quad (\text{Eq. W-25})$$

where:

E_{s,i} = Annual total volumetric GHG emissions at standard conditions from centrifugal compressor wet seals in cubic feet.

Count = Total number of centrifugal compressors for the reporter.

EF_i = Emission factor for GHG_i. Use 1.2×10^7 standard cubic feet per year per compressor for CH₄ and 5.30×10^6 standard cubic feet per year per compressor for CO₂ at 60 °F and 14.7 psia.

(8) Calculate both CH₄ and CO₂ mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(9) Calculate emissions from seal oil degassing vent vapors to flares as follows:

(i) Use the seal oil degassing vent vapor volume and gas composition as determined in paragraphs (o)(5) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine degassing vent vapor emissions from the flare.

(p) *Reciprocating compressor venting.* Calculate CH₄ and CO₂ emissions from all reciprocating compressor vents as follows. For each reciprocating compressor covered in § 98.232(d)(1), (e)(1), (f)(1), (g)(1), and (h)(1) you must conduct an annual measurement for each compressor in the mode in which it is found during the annual measurement, except as specified in paragraph (p)(9) of this section. Measure emissions from (including emissions manifolded to common vents) reciprocating rod packing vents, unit isolation valve vents, and blowdown valve vents. Record

emissions from the following vent types in the specified compressor modes during the annual measurement as follows:

(1) Operating or standby pressurized mode, blowdown vent leakage through the blowdown vent stack.

(2) Operating mode, reciprocating rod packing emissions.

(3) Not operating, depressurized mode, unit isolation valve leakage through the blowdown vent stack, without blind flanges.

(i) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years if this mode is not found in the annual measurement. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode.

(ii) [Reserved]

(4) If reciprocating rod packing and blowdown vent are connected to an open-ended vent line use one of the following two methods to calculate emissions:

(i) Measure emissions from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown vents using either calibrated bagging or high volume sampler according to methods set forth in § 98.234(c) and § 98.234(d), respectively.

(ii) Use a temporary meter such as a vane anemometer or a permanent meter such as an orifice meter to measure emissions from all vents (including emissions manifolded to a common vent) including rod packing vents and unit isolation valve leakage through blowdown vents according to methods set forth in § 98.234(b). If you do not have a permanent flow meter, you may install a port for insertion of a temporary meter or a permanent flow meter on the vents. For through-valve leakage to open ended vents, such as unit isolation valves on not operating, depressurized compressors and blowdown valves on pressurized compressors, you may use an acoustic detection device according to methods set forth in § 98.234(a).

(5) If reciprocating rod packing is not equipped with a vent line use the following method to calculate emissions:

(i) You must use the methods described in § 98.234(a) to conduct annual leak detection of equipment leaks from the packing case into an open distance piece, or from the compressor crank case breather cap or other vent with a closed distance piece.

(ii) Measure emissions found in paragraph (p)(5)(i) of this section using an appropriate meter, or calibrated bag, or high volume sampler according to methods set forth in § 98.234(b), (c), and (d), respectively.

(6) Estimate annual emissions using the flow measurement and Equation W-26 of this section.

$$E_{s,i,m} = MT_m * T_m * M_{i,m} \quad (\text{Eq. W-26})$$

where:

$E_{s,i,m}$ = Annual GHG i (either CH₄ or CO₂) volumetric emissions at standard conditions, in cubic feet.

MT_m = Measured gas emissions in standard cubic feet per hour.

T_m = Total time the compressor is in the mode for which $E_{s,i,m}$ is being calculated, in the calendar year in hours.

$M_{i,m}$ = Mole fraction of GHG i in gas; use the appropriate gas compositions in paragraph (u)(2) of this section.

(7) Calculate annual emissions from each reciprocating compressor using Equation W-27 of this section.

$$E_{s,i,m} = EF_m * T_m * GHG_i \quad (\text{Eq. W-27})$$

where:

$E_{s,i,m}$ = Annual total volumetric GHG emissions at standard conditions from each reciprocating compressor for mode-source combination m, in cubic feet.

EF_m = Reporter emission factor for each mode, m, in cubic feet per hour, from Equation W-28 of this section as calculated in paragraph (p)(7)(i) of this section.

T_m = Total time in hours per year the compressor was in each mode, m, as listed in paragraph (p)(1) through (p)(3).

GHG_i = For onshore natural gas processing facilities, concentration of GHG i, CH₄ or CO₂, in produced natural gas or feed nat-

ural gas; for other facilities listed in § 98.230(a)(4) through (a)(8), GHG_i equals 1. m = Compressor mode as listed in paragraph (p)(1) through (p)(3).

(i) You shall use the flow meter readings from measurements of operating and standby pressurized blowdown vent, operating mode vents, not operating depressurized isolation valve vent for all the reporter's compressor modes not measured in the calendar year to develop the following emission factors using Equation W-28 of this section for each mode as listed in paragraph (p)(1) through (p)(3).

$$EF_m = \frac{\sum_{p=1}^{Count_m} MT_{m,p}}{Count_m} \quad (\text{Eq. W-28})$$

where:

EF_m = Reporter emission factors for compressor in the three modes, m, in cubic feet per hour.

$MT_{m,p}$ = Flow measurements from all reciprocating compressor sources in each mode-source combination, m, for each measured compressor, p, in standard cubic feet per hour.

$Count_m$ = Total number of compressors measured in each mode, m.

m = Compressor mode-source combination as listed in (p)(1) through (p)(3).

(A) You must combine emissions for blowdown vents, measured in the operating and standby pressurized modes.

(B) The emission factors must be calculated annually. You must use all measurements from the current cal-

endar year and the preceding two calendar years, totaling three consecutive calendar years of measurements.

(ii) [Reserved]

(8) Determine if the reciprocating compressor vent vapors are sent to a vapor recovery system.

(i) Adjust the emissions estimated in paragraphs (p)(7) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

(ii) [Reserved]

(9) Onshore petroleum and natural gas production shall calculate emissions from reciprocating compressors as follows:

$$E_{s,i} = Count * EF_i \quad (\text{Eq. W-29})$$

where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from reciprocating compressors in cubic feet.

Count = Total number of reciprocating compressors for the reporter.

EF_i = Emission factor for GHG_i . Use 9.48×10^3 standard cubic feet per year per compressor for CH_4 and 5.27×10^2 standard cubic feet per year per compressor for CO_2 at 60 °F and 14.7 psia.

(10) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (u) and (v) of this section.

(q) *Leak detection and leaker emission factors.* You must use the methods described in § 98.234(a) to conduct leak detection(s) of equipment leaks from all component types listed in § 98.232(d)(7),

(e)(7), (f)(5), (g)(3), (h)(4), and (i)(1). This paragraph (q) applies to component types in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Component types in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of this paragraph (q) and do not need to be reported. If equipment leaks are detected for sources listed in this paragraph (q), calculate equipment leak emissions per component type per reporting facility using Equations W-30A or W-30B of this section for each component type. Use Equation W-30A for industry segments listed in 98.230(a)(3)-(a)(7). Use Equation W-30B for industry segments listed in 98.230(a)(8).

$$E_{s,i} = GHG_i * \sum_{p=1}^x (EF * T_p) \quad (\text{Eq. W-30A})$$

$$E_{s,i} = GHG_i * \sum_{q=t-n+1}^t \sum_{p=1}^x (EF * T_{p,q}) \quad (\text{Eq. W-30B})$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each component type in cubic feet, as specified in (q)(1) through (q)(8) of this section.

x = Total number of each component type.

EF = Leaker emission factor for specific component types listed in Table W-2 through Table W-7 of this subpart.

GHG_i = For onshore natural gas processing facilities, concentration of GHG_i , CH_4 or CO_2 , in the total hydrocarbon of the feed natural gas; for onshore natural gas transmission compression and underground natural gas storage, GHG_i equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2 ; for LNG storage and LNG import and export equipment, GHG_i equals 1 for CH_4 and 0 for CO_2 ; and for natural gas distribution, GHG_i equals 1 for CH_4 and 1.1×10^{-2} CO_2 .

T_p = The total time the component, p , was found leaking and operational, in hours. If one leak detection survey is conducted, assume the component was leaking for the entire calendar year. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the previous survey (if not found leaking in the previous survey) or the beginning of the calendar year (if it was found leaking in the previous survey). For the last leak detection survey in the calendar year, assume that all leaking components continue to leak until the end of the calendar year.

t = Calendar year of reporting.

n = The number of years over which one complete cycle of leak detection is conducted over all the T-D transfer stations in a natural gas distribution facility; $0 < n \leq 5$. For the first $(n-1)$ calendar years of reporting the summation in Equation W-30B should be for years that the data is available.

$T_{p,q}$ = The total time the component, p , was found leaking and operational, in hours, in year q . If one leak detection survey is conducted, assume the component was leaking for the entire period n . If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking

since the previous survey (if not found to be leaking in the previous survey) or the beginning of the calendar year (if it was found to be leaking in the previous survey). For the last leak detection survey in the cycle, assume that all leaking components continue to leak until the end of the cycle.

(1) You must select to conduct either one leak detection survey in a calendar year or multiple complete leak detection surveys in a calendar year. The number of leak detection surveys selected must be conducted during the calendar year.

(2) Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions using calculations in paragraph (v) of this section.

(3) Onshore natural gas processing facilities shall use the appropriate default leaker emission factors listed in Table W-2 of this subpart for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(4) Onshore natural gas transmission compression facilities shall use the appropriate default leaker emission factors listed in Table W-3 of this subpart for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(5) Underground natural gas storage facilities for storage stations shall use the appropriate default leaker emission factors listed in Table W-4 of this subpart for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(6) LNG storage facilities shall use the appropriate default leaker emission factors listed in Table W-5 of this subpart for equipment leaks detected from valves, pump seals, connectors, and other.

(7) LNG import and export facilities shall use the appropriate default leaker

emission factors listed in Table W-6 of this subpart for equipment leaks detected from valves, pump seals, connectors, and other.

(8) Natural gas distribution facilities for above grade transmission-distribution transfer stations, shall use the appropriate default leaker emission factors listed in Table W-7 of this subpart for equipment leaks detected from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines. Leak detection at natural gas distribution facilities is only required at above grade stations that qualify as transmission-distribution transfer stations. Below grade transmission-distribution transfer stations and all metering-regulating stations that do meet the definition of transmission-distribution transfer stations are not required to perform component leak detection under this section.

(i) Natural gas distribution facilities may choose to conduct leak detection at the T-D transfer stations over multiple years, not exceeding a five year

period to cover all T-D transfer stations. If the facility chooses to use the multiple year option then the number of T-D transfer stations that are monitored in each year should be approximately equal across all years in the cycle without monitoring the same station twice during the multiple year survey.

(ii) [Reserved]

(r) *Population count and emission factors.* This paragraph applies to emissions sources listed in §98.232 (c)(21), (f)(5), (g)(3), (h)(4), (i)(2), (i)(3), (i)(4), (i)(5), and (i)(6) on streams with gas content greater than 10 percent CH₄ plus CO₂ by weight. Emissions sources in streams with gas content less than 10 percent CH₄ plus CO₂ by weight do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of paragraph (r) of this section and do not need to be reported. Calculate emissions from all sources listed in this paragraph using Equation W-31 of this section.

$$E_{s,i} = Count_s * EF_s * GHG_i * T_s \quad (\text{Eq. W-31})$$

Where:

$E_{s,i}$ = Annual volumetric GHG emissions at standard conditions from each component type in cubic feet.

$Count_s$ = Total number of this type of emission source at the facility. For onshore petroleum and natural gas production, average component counts are provided by major equipment piece in Tables W-1B and Table W-1C of this subpart. Use average component counts as appropriate for operations in Eastern and Western U.S., according to Table W-1D of this subpart. Underground natural gas storage shall count the components listed for population emission factors in Table W-4. LNG Storage shall count the number of vapor recovery compressors. LNG import and export shall count the number of vapor recovery compressors. Natural gas distribution shall count the meter/regulator runs as described in paragraph (r)(6) of this section.

EF = Population emission factor for the specific component type, as listed in Table W-1A and Tables W-3 through Table W-7 of this subpart. Use appropriate population emission factor for operations in

Eastern and Western U.S., according to Table W-1D of this subpart. EF for meter/regulator runs at above grade metering-regulating stations is determined in Equation W-32 of this section.

GHG_i = For onshore petroleum and natural gas production facilities, concentration of GHG_i, CH₄ or CO₂, in produced natural gas as defined in paragraph (u)(2) of this section; for onshore natural gas transmission compression and underground natural gas storage, GHG_i equals 0.975 for CH₄ and 1.1×10^{-2} for CO₂; for LNG storage and LNG import and export equipment, GHG_i equals 1 for CH₄ and 0 for CO₂; and for natural gas distribution, GHG_i equals 1 for CH₄ and 1.1×10^{-2} CO₂.

T_s = Average estimated time that each component type associated with the equipment leak emission was operational in the calendar year, in hours, using engineering estimate based on best available data.

(1) Calculate both CH₄ and CO₂ mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(2) Onshore petroleum and natural gas production facilities shall use the appropriate default population emission factors listed in Table W-1A of this subpart for equipment leaks from valves, connectors, open ended lines, pressure relief valves, pump, flanges, and other. Major equipment and components associated with gas wells are considered gas service components in reference to Table W-1A of this subpart and major natural gas equipment in reference to Table W-1B of this subpart. Major equipment and components associated with crude oil wells are considered crude service components in reference to Table W-1A of this subpart and major crude oil equipment in reference to Table W-1C of this subpart. Where facilities conduct EOR operations the emissions factor listed in Table W-1A of this subpart shall be used to estimate all streams of gases, including recycle CO₂ stream. The component count can be determined using either of the methodologies described in this paragraph (r)(2). The same methodology must be used for the entire calendar year.

(i) *Component Count Methodology 1.* For all onshore petroleum and natural gas production operations in the facility perform the following activities:

(A) Count all major equipment listed in Table W-1B and Table W-1C of this subpart. For meters/piping, use one meters/piping per well-pad.

(B) Multiply major equipment counts by the average component counts listed in Table W-1B and W-1C of this subpart for onshore natural gas production and onshore oil production, respectively. Use the appropriate factor in Table W-1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table W-1D of this subpart.

(ii) *Component Count Methodology 2.* Count each component individually for the facility. Use the appropriate factor in Table W-1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table W-1D of this subpart.

(3) Underground natural gas storage facilities for storage wellheads shall

use the appropriate default population emission factors listed in Table W-4 of this subpart for equipment leak from connectors, valves, pressure relief valves, and open ended lines.

(4) LNG storage facilities shall use the appropriate default population emission factors listed in Table W-5 of this subpart for equipment leak from vapor recovery compressors.

(5) LNG import and export facilities shall use the appropriate default population emission factor listed in Table W-6 of this subpart for equipment leak from vapor recovery compressors.

(6) Natural gas distribution facilities shall use the appropriate emission factors as described in paragraph (r)(6) of this section.

(i) Below grade metering-regulating stations; distribution mains; and distribution services, shall use the appropriate default population emission factors listed in Table W-7 of this subpart. Below grade T-D transfer stations shall use the emission factor for below grade metering-regulating stations.

(ii) Emissions from all above grade metering-regulating stations (including above grade TD transfer stations) shall be calculated by applying the emission factor calculated in Equation W-32 and the total count of meter/regulator runs at all above grade metering-regulating stations (inclusive of TD transfer stations) to Equation W-31. The facility wide emission factor in Equation W-32 will be calculated by using the total volumetric GHG emissions at standard conditions for all equipment leak sources calculated in Equation W-30B in paragraph (q)(8) of this section and the count of meter/regulator runs located at above grade transmission-distribution transfer stations that were monitored over the years that constitute one complete cycle as per paragraph (q)(8)(i) of this section. A meter on a regulator run is considered one meter/regulator run. Reporters that do not have above grade T-D transfer stations shall report a count of above grade metering-regulating stations only and do not have to comply with § 98.236(c)(16)(xix).

$$EF = \frac{E_{s,i} \div 8760}{Count} \quad (\text{Eq. W-32})$$

Where:

EF = Facility emission factor for a meter/regulator run per component type at above grade metering-regulating for GHG_i in cubic feet per meter/regulator run per hour.

E_{s,i} = Annual volumetric GHG i emissions, CO₂ or CH₄ at standard condition from each component type at all above grade TD transfer stations, from Equation W-30B.

Count = Total number of meter/regulator runs at all TD transfer stations that were monitored over the years that constitute one complete cycle as per (q)(8)(i) of this section.

8760 = Conversion to hourly emissions

(s) *Offshore petroleum and natural gas production facilities.* Report CO₂, CH₄, and N₂O emissions for offshore petroleum and natural gas production from all equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304.

(1) Offshore production facilities under BOEMRE jurisdiction shall report the same annual emissions as calculated and reported by BOEMRE in data collection and emissions estimation study published by BOEMRE referenced in 30 CFR 250.302 through 304 (GOADS).

(i) For any calendar year that does not overlap with the most recent BOEMRE emissions study publication year, report the most recent BOEMRE reported emissions data published by BOEMRE referenced in 30 CFR 250.302 through 304 (GOADS). Adjust emissions based on the operating time for the facility relative to the operating time in the most recent BOEMRE published study.

(ii) [Reserved]

(2) Offshore production facilities that are not under BOEMRE jurisdiction shall use monitoring methods and calculation methodologies published by BOEMRE referenced in 30 CFR 250.302

through 304 to calculate and report emissions (GOADS).

(i) For any calendar year that does not overlap with the most recent BOEMRE emissions study publication, report the most recent reported emissions data with emissions adjusted based on the operating time for the facility relative to operating time in the previous reporting period.

(ii) [Reserved]

(3) If BOEMRE discontinues or delays their data collection effort by more than 4 years, then offshore reporters shall once in every 4 years use the most recent BOEMRE data collection and emissions estimation methods to report emission from the facility sources.

(4) For either first or subsequent year reporting, offshore facilities either within or outside of BOEMRE jurisdiction that were not covered in the previous BOEMRE data collection cycle shall use the most recent BOEMRE data collection and emissions estimation methods published by BOEMRE referenced in 30 CFR 250.302 through 304 to calculate and report emissions (GOADS) to report emissions.

(t) *Volumetric emissions.* If equation parameters in § 98.233 are already at standard conditions, which results in volumetric emissions at standard conditions, then this paragraph does not apply. Calculate volumetric emissions at standard conditions as specified in paragraphs (t)(1) or (2) of this section, with actual pressure and temperature determined by engineering estimates based on best available data unless otherwise specified.

(1) Calculate natural gas volumetric emissions at standard conditions using actual natural gas emission temperature and pressure, and Equation W-33 of this section for conversions of E_{a,n} or conversions of FR_a (whether sub-sonic or sonic).

$$E_{s,n} = \frac{E_{a,n} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s} \quad (\text{Eq. W-33})$$

where:

$E_{s,n}$ = Natural gas volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet, except $E_{s,n}$ equals $FR_{s,p}$ for each well p when calculating either subsonic or sonic flowrates under 98.233(g).

$E_{a,n}$ = Natural gas volumetric emissions at actual conditions in cubic feet, except $E_{a,n}$ equals $FR_{a,p}$ for each well p when calculating either subsonic or sonic flowrates under 98.233(g).

T_s = Temperature at standard conditions (60 °F).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (14.7 psia).

P_a = Absolute pressure at actual conditions (psia).

(2) Calculate GHG volumetric emissions at standard conditions using actual GHG emissions temperature and pressure, and Equation W-34 of this section.

$$E_{s,i} = \frac{E_{a,i} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s} \quad (\text{Eq. W-34})$$

where:

$E_{s,i}$ = GHG i volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet.

$E_{a,i}$ = GHG i volumetric emissions at actual conditions in cubic feet.

T_s = Temperature at standard conditions (60 °F).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (14.7 psia).

P_a = Absolute pressure at actual conditions (psia).

(3) Reporters using 68 °F for standard temperature may use the ratio 519.67/

527.67 to convert volumetric emissions from 68 °F to 60 °F.

(u) *GHG volumetric emissions.* Calculate GHG volumetric emissions at standard conditions as specified in paragraphs (u)(1) and (2) of this section, with mole fraction of GHGs in the natural gas determined by engineering estimate based on best available data unless otherwise specified.

(1) Estimate CH₄ and CO₂ emissions from natural gas emissions using Equation W-35 of this section.

$$E_{s,i} = E_{s,n} * M_i \quad (\text{Eq. W-35})$$

where:

$E_{s,i}$ = GHG i (either CH₄ or CO₂) volumetric emissions at standard conditions in cubic feet.

$E_{s,n}$ = Natural gas volumetric emissions at standard conditions in cubic feet.

M_i = Mole fraction of GHG i in the natural gas.

(2) For Equation W-35 of this section, the mole fraction, M_i , shall be the annual average mole fraction for each sub-basin category or facility, as speci-

fied in paragraphs (u)(2)(i) through (vii) of this section.

(i) GHG mole fraction in produced natural gas for onshore petroleum and natural gas production facilities. If you have a continuous gas composition analyzer for produced natural gas, you must use an annual average of these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then you

must use an annual average gas composition based on your most recent available analysis of the sub-basin category or facility, as applicable to the emission source.

(ii) GHG mole fraction in feed natural gas for all emissions sources upstream of the de-methanizer or dew point control and GHG mole fraction in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole percent in feed natural gas liquid for all streams. If you have a continuous gas composition analyzer on feed natural gas, you must use these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in § 98.234(b).

(iii) GHG mole fraction in transmission pipeline natural gas that passes through the facility for the onshore natural gas transmission compression industry segment. You may use a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas.

(iv) GHG mole fraction in natural gas stored in the underground natural gas storage industry segment. You may use a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas.

(v) GHG mole fraction in natural gas stored in the LNG storage industry segment. You may use a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas.

(vi) GHG mole fraction in natural gas stored in the LNG import and export industry segment. For export facilities that receive gas from transmission pipelines, you may use a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas.

(vii) GHG mole fraction in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities. You may use a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas.

(v) *GHG mass emissions.* Calculate GHG mass emissions in carbon dioxide equivalent by converting the GHG volumetric emissions at standard conditions into mass emissions using Equation W-36 of this section.

$$Mass_i = E_{s,i} * \rho_i * GWP * 10^{-3} \quad (\text{Eq. W-36})$$

Where:

$Mass_i$ = GHG_i (either CH₄, CO₂, or N₂O) mass emissions in metric tons CO₂e.

$E_{s,i}$ = GHG_i (either CH₄, CO₂, or N₂O) volumetric emissions at standard conditions, in cubic feet.

P_i = Density of GHG_i. Use 0.0526 kg/ft³ for CO₂ and N₂O, and 0.0192 kg/ft³ for CH₄ at 60 °F and 14.7 psia.

GWP = Global warming potential, 1 for CO₂, 25 for CH₄, and 298 for N₂O.

(w) *EOR injection pump blowdown.* Calculate CO₂ pump blowdown emissions as follows:

(1) Calculate the total volume in cubic feet (including pipelines, manifolds and vessels) between isolation valves.

(2) Retain logs of the number of blowdowns per calendar year.

(3) Calculate the total annual venting emissions using Equation W-37 of this section:

$$Mass_{CO_2} = N * V_v * R_c * GHG_{CO_2} * 10^{-3} \quad (\text{Eq. W-37})$$

§ 98.233

40 CFR Ch. I (7–1–14 Edition)

Where:

Mass_{CO2} = Annual EOR injection gas venting emissions in metric tons from blowdowns.

N = Number of blowdowns for the equipment in the calendar year.

V_v = Total volume in cubic feet of blowdown equipment chambers (including pipelines, manifolds and vessels) between isolation valves.

R_c = Density of critical phase EOR injection gas in kg/ft³. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice to determine density of super critical EOR injection gas.

GHG_{CO2} = Mass fraction of CO₂ in critical phase injection gas.

1 × 10⁻³ = Conversion factor from kilograms to metric tons.

(x) EOR hydrocarbon liquids dissolved CO₂. Calculate dissolved CO₂ in hydrocarbon liquids produced through EOR operations as follows:

(1) Determine the amount of CO₂ retained in hydrocarbon liquids after flashing in tankage at STP conditions. Annual samples must be taken according to methods set forth in § 98.234(b) to determine retention of CO₂ in hydrocarbon liquids immediately downstream of the storage tank. Use the annual analysis for the calendar year.

(2) Estimate emissions using Equation W-38 of this section.

$$\text{Mass}_{\text{CO}_2} = S_{\text{hl}} * V_{\text{hl}} \quad (\text{Eq. W-38})$$

Where:

Mass_{CO2} = Annual CO₂ emissions from CO₂ retained in hydrocarbon liquids produced through EOR operations beyond tankage, in metric tons.

S_{hl} = Amount of CO₂ retained in hydrocarbon liquids in metric tons per barrel, under standard conditions.

V_{hl} = Total volume of hydrocarbon liquids produced at the EOR operations in barrels in the calendar year.

(y) [Reserved]

(z) *Onshore petroleum and natural gas production and natural gas distribution combustion emissions.* Calculate CO₂, CH₄, and N₂O combustion-related emissions from stationary or portable equipment, except as specified in paragraph (z)(3) and (z)(4) of this section, as follows:

(1) If a fuel combusted in the stationary or portable equipment is listed in Table C-1 of subpart C of this part, or is a blend containing one or more fuels listed in Table C-1, calculate emissions according to (z)(1)(i). If the fuel combusted is natural gas and is of pipeline quality specification and has a minimum high heat value of 950 Btu per standard cubic foot, use the calculation methodology described in (z)(1)(i) and you may use the emission factor provided for natural gas as listed in Table C-1. If the fuel is natural gas, and is not pipeline quality or has a high heat value of less than 950 Btu per

standard cubic feet, calculate emissions according to (z)(2). If the fuel is field gas, process vent gas, or a blend containing field gas or process vent gas, calculate emissions according to (z)(2).

(i) For fuels listed in Table C-1 or a blend containing one or more fuels listed in Table C-1, calculate CO₂, CH₄, and N₂O emissions according to any Tier listed in subpart C of this part. You must follow all applicable calculation requirements for that tier listed in 98.33, any monitoring or QA/QC requirements listed for that tier in 98.34, any missing data procedures specified in 98.35, and any recordkeeping requirements specified in 98.37.

(ii) Emissions from fuel combusted in stationary or portable equipment at onshore natural gas and petroleum production facilities and at natural gas distribution facilities will be reported according to the requirements specified in 98.236(c)(19) and not according to the reporting requirements specified in subpart C of this part.

(2) For fuel combustion units that combust field gas, process vent gas, a blend containing field gas or process vent gas, or natural gas that is not of pipeline quality or that has a high heat value of less than 950 Btu per standard cubic feet, calculate combustion emissions as follows:

Environmental Protection Agency

§ 98.233

(i) You may use company records to determine the volume of fuel combusted in the unit during the reporting year.

(ii) If you have a continuous gas composition analyzer on fuel to the combustion unit, you must use these compositions for determining the concentration of gas hydrocarbon constituent in the flow of gas to the unit. If you do not have a continuous gas

composition analyzer on gas to the combustion unit, you must use the appropriate gas compositions for each stream of hydrocarbons going to the combustion unit as specified in the applicable paragraph in (u)(2) of this section.

(iii) Calculate GHG volumetric emissions at actual conditions using Equations W-39A and W-39B of this section:

$$E_{a,CO_2} = (V_a * Y_{CO_2}) + \eta * \sum_{j=1}^5 V_a * Y_j * R_j \quad (\text{Eq. W-39A})$$

$$E_{a,CH_4} = V_a * (1 - \eta) * Y_{CH_4} \quad (\text{Eq. W-39B})$$

Where:

E_{a,CO_2} = Contribution of annual CO₂ emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.

V_a = Volume of gas sent to combustion unit in cubic feet, during the year.

Y_{CO_2} = Concentration of CO₂ constituent in gas sent to combustion unit.

E_{a,CH_4} = Contribution of annual CH₄ emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.

η = Fraction of gas combusted for portable and stationary equipment determined using engineering estimation. For internal combustion devices, a default of 0.995 can be used.

Y_j = Concentration of gas hydrocarbon constituents j (such as methane, ethane,

propane, butane, and pentanes plus) in gas sent to combustion unit.

R_j = Number of carbon atoms in the gas hydrocarbon constituent j; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus, in gas sent to combustion unit.

Y_{CH_4} = Concentration of methane constituent in gas sent to combustion unit.

(iv) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(v) Calculate both combustion-related CH₄ and CO₂ mass emissions from volumetric CH₄ and CO₂ emissions using calculation in paragraph (v) of this section.

(vi) Calculate N₂O mass emissions using Equation W-40 of this section.

$$Mass_{N_2O} = (1 \times 10^{-3}) \times Fuel \times HHV \times EF \times GWP \quad (\text{Eq. W-40})$$

Where:

$Mass_{N_2O}$ = Annual N₂O emissions from the combustion of a particular type of fuel (metric tons CO₂e).

Fuel = Mass or volume of the fuel combusted (mass or volume per year, choose appropriately to be consistent with the units of HHV).

HHV = For the higher heating value for field gas or process vent gas, use 1.235×10^{-3} mmBtu/scf for HHV.

EF = Use 1.0×10^{-4} kg N₂O/mmBtu.

1×10^{-3} = Conversion factor from kilograms to metric tons.

GWP = Global warming potential, as listed in Table A-1 of subpart A of this part.

(3) External fuel combustion sources with a rated heat capacity equal to or less than 5 mmBtu/hr do not need to report combustion emissions or include these emissions for threshold determination in § 98.231(a). You must report

the type and number of each external fuel combustion unit.

(4) Internal fuel combustion sources, not compressor-drivers, with a rated heat capacity equal to or less than 1 mmBtu/hr (or the equivalent of 130 horsepower), do not need to report combustion emissions or include these emissions for threshold determination in § 98.231(a). You must report the type and number of each internal fuel combustion unit.

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 80575, Dec. 23, 2011; 77 FR 51490, Aug. 24, 2012; 78 FR 71960, Nov. 29, 2013]

§ 98.234 Monitoring and QA/QC requirements.

The GHG emissions data for petroleum and natural gas emissions sources must be quality assured as applicable as specified in this section. Offshore petroleum and natural gas production facilities shall adhere to the monitoring and QA/QC requirements as set forth in 30 CFR 250.

(a) You must use any of the methods described as follows in this paragraph to conduct leak detection(s) of equipment leaks and through-valve leakage from all source types listed in § 98.233(k), (o), (p) and (q) that occur during a calendar year, except as provided in paragraph (a)(4) of this section.

(1) *Optical gas imaging instrument.* Use an optical gas imaging instrument for equipment leak detection in accordance with 40 CFR part 60, subpart A, § 60.18 of the *Alternative work practice for monitoring equipment leaks*, § 60.18(i)(1)(i); § 60.18(i)(2)(i) except that the monitoring frequency shall be annual using the detection sensitivity level of 60 grams per hour as stated in 40 CFR Part 60, subpart A, Table 1: *Detection Sensitivity Levels*; § 60.18(i)(2)(ii) and (iii) except the gas chosen shall be methane, and § 60.18(i)(2)(iv) and (v); § 60.18(i)(3); § 60.18(i)(4)(i) and (v); including the requirements for daily instrument checks and distances, and excluding requirements for video records. Any emissions detected by the optical gas imaging instrument is a leak unless screened with Method 21 (40 CFR part 60, appendix A–7) monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, you must

operate the optical gas imaging instrument to image the source types required by this subpart in accordance with the instrument manufacturer's operating parameters. Unless using methods in paragraph (a)(2) of this section, an optical gas imaging instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) *Method 21.* Use the equipment leak detection methods in 40 CFR part 60, appendix A–7, Method 21. If using Method 21 monitoring, if an instrument reading of 10,000 ppm or greater is measured, a leak is detected. Inaccessible emissions sources, as defined in 40 CFR part 60, are not exempt from this subpart. Owners or operators must use alternative leak detection devices as described in paragraph (a)(1) or (a)(2) of this section to monitor inaccessible equipment leaks or vented emissions.

(3) *Infrared laser beam illuminated instrument.* Use an infrared laser beam illuminated instrument for equipment leak detection. Any emissions detected by the infrared laser beam illuminated instrument is a leak unless screened with Method 21 monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, you must operate the infrared laser beam illuminated instrument to detect the source types required by this subpart in accordance with the instrument manufacturer's operating parameters.

(4) [Reserved]

(5) *Acoustic leak detection device.* Use the acoustic leak detection device to detect through-valve leakage. When using the acoustic leak detection device to quantify the through-valve leakage, you must use the instrument manufacturer's calculation methods to quantify the through-valve leak. When using the acoustic leak detection device, if a leak of 3.1 scf per hour or greater is calculated, a leak is detected. In addition, you must operate the acoustic leak detection device to monitor the source valves required by this subpart in accordance with the instrument manufacturer's operating parameters. Acoustic stethoscope type devices designed to detect through valve leakage when put in contact with